UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

OFFICE OF
AIR QUALITY PLANNING
AND STANDARDS

MEMORANDUM

Subject: Response to Public Comments on Proposed Standards of Performance for Stationary Gas Turbines

From: Jaime Pagán, ESD Combustion Group

To: EPA Docket OAR-2002-0053

Date: March 24, 2004

On April 14, 2003, a direct final rule to amend the standards of performance for stationary gas turbines (68 FR 17990) was published, along with a parallel proposal (68 FR 18003) to be used as a basis for final action in the event that adverse comments were received on the direct final rule amendments. We received adverse comments on the direct final rule, as well as a request for a public hearing. The direct final rule was subsequently withdrawn on May 28, 2003 (68 FR 31611). The purpose of this document is to present a summary of the public comments that EPA received on the proposed standards and the responses developed. This summary of comments and responses serves as the basis for revisions made to the standards between proposal and promulgation.

We received 23 public comments on the proposed rule. On May 14, 2003, a public hearing on the proposed standards of performance for stationary gas turbines was held at the EPA facility in Research Triangle Park, NC. Comments from the public hearing on the proposed standards were recorded, and a transcript of the hearing was placed in the project docket. A listing of all persons submitting comments, their affiliation, and the Edocket document ID for their comments is presented in Table 1 and Table 2. The comments can be obtained online from the EPA's Edocket website (http://www.epa.gov/edocket). The docket number for this rulemaking is OAR-2002-0053. In this document, commenters are identified by the Edocket Document ID of their comments.

Table 1. List of Commenters on the Proposed Standards of Performance for Stationary Gas Turbines

EDocket ID Number	Commenter/Affiliation
OAR-2002-0053-0003	Mr. Stephen A. Loeschner Fort Wayne, IN
OAR-2002-0053-0004	Daniel S. Hedrick Environmental Specialist II Associated Electric Cooperative, Inc.
OAR-2002-0053-0005	Stephen B. Ellingson Environmental Compliance Director Koch Mineral Services LLC Wichita, KS
OAR-2002-0053-0008	Jim Pfeiffer Air Specialist - Alaska BP Exploration Alaska Anchorage, AK
OAR-2002-0053-0010	Leslie Witherspoon Solar Turbines, Incorporated San Diego, CA
OAR-2002-0053-0011	Ted Cromwell Co-Leader, Air Team American Chemistry Council
OAR-2002-0053-0012	Jeff Abboud Executive Director Gas Turbine Association Great Falls, VA
OAR-2002-0053-0013	Lisa Beal Director, Environmental Affairs Interstate Natural Gas Association of America Washington, DC
OAR-2002-0053-0014	Lauren E. Freeman Hunton & Williams LLP on behalf of UARG Washington, DC

EDocket ID Number	Commenter/Affiliation
OAR-2002-0053-0015	Matthew O. Tanzer EHS Counsel - Air Programs General Electric Company Fairfield, CT
OAR-2002-0053-0016	Amy H. Wright Director - Environmental Management Dayton Power and Light Company Dayton, OH
OAR-2002-0053-0018	Randy Poteet Senior Environmental Coordinator ConocoPhillips Alaska, Inc. Anchorage, AK
OAR-2002-0053-0019	Don Mark Anthony Air Quality Engineer Alyeska Pipeline Service Company Fairbanks, AK
OAR-2002-0053-0020	George S. Lipka, P.E. Principal Engineer EarthTech MA
OAR-2002-0053-0021	Gregory M. Adams Assistant Departmental Engineer Office Engineering Department Los Angeles County Sanitation Districts Whittier, CA
OAR-2002-0053-0022	PacifiCorp Salt Lake City, UT
OAR-2002-0053-0024	Michael W. Stroben Corporate Responsibility Manager Duke Energy Corp. Charlotte, NC
OAR-2002-0053-0025	Bob Machaver Lincoln, MA

EDocket ID Number	Commenter/Affiliation
OAR-2002-0053-0027	Matthew O. Tanzer EHS Counsel - Air Programs General Electric Company Fairfield, CT
OAR-2002-0053-0028	David P. Skipton, P.E. Senior Environmental Engineer Lincoln Electric System Lincoln, NE
OAR-2002-0053-0030	Robert Ukeiley Counsel for Sierra Club Georgia Center for Law in the Public Interest Atlanta, GA
OAR-2002-0053-0048	Patrick J. Nugent Executive Director Association of Texas Intrastate Natural Gas Pipelines (ATINGP)

Table 2. Individuals Providing Verbal Comments at the Public Hearing of the Proposed Standards of Performance for Stationary Gas Turbines

EDocket ID Number	Commenter/Affiliation
OAR-2002-0053-0047	Fiji George El Paso Pipeline Group (on behalf of the Interstate Natural Gas Association of America)

Many commenters expressed support for the comments submitted by other commenters. Table 3 shows those commenters and the comments that they supported.

Table 3. List of Commenters Expressing Support for Other Comments

Commenter	Supports Comments of:
OAR-2002-0053-0011	OAR-2002-0053-0027
OAR-2002-0053-0016	OAR-2002-0053-0014
OAR-2002-0053-0018	OAR-2002-0053-0019
OAR-2002-0054-0048	OAR-2002-0053-0010, OAR-2002-0053-0013

Summary of Public Comments

The summary of public comments and responses is organized as follows:

1.0 Fuel Sampling/Sulfur Content

2.0 Monitoring
- 2.1 Continuous Monitoring
- 2.2 CEMS
- 2.3 Parametric Monitoring
- 2.4 Other

3.0 Test Methods and Procedures

4.0 ISO Correction

5.0 Emission Standards

6.0 Definitions

7.0 Clarifications

8.0 Other

1.0 Fuel Sampling/Sulfur Content

1.1 Comment: One commenter (OAR-2002-0053-0003) requested that "EPA excise all regulatory text in re nitrogen in fuel."

Response: We are unable to address this comment as it was not clear the reason nor rationale for this statement.

1.2 Comment: One commenter (OAR-2002-0053-0003) opposed the elimination of daily fuel total sulfur content sampling for turbines combusting natural gas. The commenter felt that eliminating the sampling requirement is not environmentally beneficial and creates a situation where the emission of sulfur compounds is presumptive with no measured foundation. The commenter provided suggested sampling schedules for turbines firing pipeline natural gas and turbines firing natural gas.

Response: The proposed revision did not eliminate requirements. Rather, it provides optional (not mandatory) relief from monitoring the sulfur content of natural gas. Natural gas was defined in the proposed rule as having a sulfur content of 20 grains or less of total sulfur per 100 standard cubic feet, which equates to 0.068 weight percent sulfur, or 680 parts per million by weight (ppmw). When natural gas is combusted, there is no possibility of exceeding the subpart GG sulfur limit of 0.8 weight percent.

The commenter is not correct in asserting that this new provision is "presumptive with no measured foundation." The final rule requires the owner or operator to document that the fuel meets the definition of natural gas in order to obtain the regulatory relief.

1.3 Comment: One commenter (OAR-2002-0053-0004) believed that EPA should provide additional options to sampling for nitrogen and sulfur content in fuel oil burned in the turbine(s). The commenter stated that EPA should clarify the requirement to conduct daily sampling only "while the unit is operating." Similarly, one commenter (OAR-2002-0053-0016) stated that if no fuel oil has been combusted in a reporting period, failure to sample deliveries of fuel oil should not be considered a deviation.

Commenter OAR-2002-0053-0004 also requested that installations with multiple units located at a facility but operated from the same fuel oil forwarding skid, tank, or fuel oil lines should be allowed to take one sample for the day for all units operated during an official "unit operating day." According to the commenter, sampling and analysis of fuel oil samples taken from units that operate less than 500 hours a year is costly, and the amount of SO_2 emitted from these peaking gas turbines is negligible to immeasurable.

Response: The proposed revisions to § 60.334 (i)(1) provide owners and operators with many options for scheduling of fuel oil sampling. They may sample on a per delivery basis; therefore, daily sampling is not a requirement. In addition, failure to sample deliveries of fuel oil if no fuel oil has been combusted is not an excess emission if one of the other schedules has been retained. Note that the term "deviation" has been removed from the final rule due to overlap in its definition with "excess emission." All instances that were previously labeled "deviations" are now referred to as "excess emissions." An owner or operator may utilize flow proportional sampling, which would require samples only if fuel oil is being combusted. We have reexamined the sections of Appendix D of part 75 referenced in § 60.334 (i)(1), and feel that owners and operators are not precluded from taking one sample for the day for all units operated during an official "unit operating day." No changes have been made to the proposed regulatory text in response to this comment.

1.4 Comment: One commenter (OAR-2002-0053-0004) opposed what they considered to be conflicting sulfur compliance standards in fuel used between 40 CFR part 75 and 40 CFR part 60. The commenter noted that 40 CFR part 75 allows a 0.5 grains per 100 scf sulfur content, whereas 40 CFR part 60 had a proposed range between 0.4 to 0.8 percent sulfur. The commenter requested that EPA provide a chart or table that will convert compliance in either standard.

Response: We did not propose to change the part 60 sulfur content allowance in this rulemaking. Section 60.333 (b) states that "No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight (8000 ppmw)." We did not propose a range of 0.4 to 0.8 percent sulfur. The 0.8 percent sulfur requirement in Subpart GG existed prior to the proposal and thus, was not part of this rulemaking. In fact, the only change that was made to § 60.333 is clarification that 0.8 percent by weight sulfur is equivalent to 8000 ppmw. We do not feel that a conversion chart is necessary. The conversion factor from grains per standard cubic foot to ppmw and percent weight is to multiply gr/scf by 3.4×10^3 to get ppmw, then divide the product by 10^4 to get percent weight.

1.5 Comment: One commenter (OAR-2002-0053-0027) inquired whether the 20 grain of sulfur per 100 standard cubic feet limit in the definition of natural gas accounts for the sulfur in mercaptans or other odorizers. The commenter also questioned whether a gas containing more than 20 grains per 100 standard cubic feet would mean it is not natural gas. The commenter requested that EPA make it clear that the 20 grains per 100 standard cubic feet is not a limit, but rather is typical of pipeline natural gas in the United States.

Response: The definition of natural gas in 40 CFR part 60 allows for 20 grains of sulfur per 100 standard cubic feet, and this is for total sulfur, which would include any sulfur in mercaptans or other odorizers. We are not making 20 grains per 100 standard cubic feet a limit for this rule, but rather, providing those owners and operators whose fuel meets this definition of natural gas the flexibility of not having to sample their fuel for sulfur content. Owners and operators may use natural gas with a higher sulfur content, but will still have to sample according to § 60.334 (j)(2).

1.6 Comment: One commenter (OAR-2002-0053-0019) suggested that EPA provide the total sulfur specification in the definition of natural gas in units of measurement that are more universally understood not only in the natural gas utility industry, but also in the upstream petroleum exploration and production industry. The commenter recommended that EPA provide the equivalent sulfur content in units of parts per million by volume (ppmv).

Response: The equivalent sulfur content in units of parts per million by volume is 338 ppmv (this is at 20 degrees C). This has been added to the preamble, where equivalent sulfur contents in weight percent and parts per million by weight are given. In addition, equivalents in ppmw, ppmv, and weight percent sulfur have been added to the definition of natural gas in the final rule, § 60.331(u) .

1.7 Comment: One commenter (OAR-2002-0053-0019) recommended that EPA add a definition for "low sulfur diesel fuel" consistent with the latest definition in 40 CFR part 72. The commenter stated that fuel sulfur sampling is unnecessary for fuels that qualify as diesel fuel as defined in 40 CFR § 72.2 because such fuels have a sulfur content well below the subpart GG standard, and EPA should provide relief from fuel sulfur content monitoring for owners and operators of turbines that combust qualifying fuel.

Response: This comment was not incorporated chiefly because EPA believes that documentation is required to demonstrate that fuel oil initially qualifies and continues to qualify as diesel fuel. Such documentation can only be provided by periodic fuel sampling and analysis. Furthermore, the oil sampling requirements of Subpart GG are not burdensome. The oil sampling provisions in of Part 75, Appendix D, section 2.2 have been incorporated by reference into Subpart GG. Those provisions give the owner or operator several different fuel sampling options (i.e., daily sampling, flow proportional sampling, sampling after each addition of oil to the unit's storage tank, and sampling of each delivery (i.e., each fuel lot)). Additionally, part 75, which Subpart GG references, allows the results of sampling performed by the fuel supplier to be used to demonstrate compliance (see Appendix D, section 2.2.4.3 (c)).

The definition for "very low sulfur fuel,"in § 72.2 has three parts, i.e., any fuel which: (1) has a total sulfur content no greater than 0.05 percent sulfur by weight; (2) meets the definition of natural gas in § 72.2; or (3) is a gaseous fuel with total sulfur content no greater than 20 grains per 100 scf.

We have examined the three ASTMs cited in 40 CFR 72.2 under the definition of "diesel fuel": the most recent versions of ASTM D 975-91 (975-02), ASTM D 2880-90a (2880-00), and ASTM D 396-90a (396-02). The ASTM D 975-02 and ASTM D 396-02 specify a sulfur content of 0.05 percent mass for the low sulfur fuels, which is lower than the sulfur content specified in the proposed definition for natural gas in Subpart GG (equivalent of 0.068 weight percent). However, the ASTM D 2880-00 does not have a specification for the sulfur content.

1.8 Comment: Three commenters (OAR-2002-0053-0010, OAR-2002-0053-0013, and OAR-2002-0053-0047) supported EPA's proposal to remove requirements to monitor sulfur and nitrogen content for natural gas.

Response: No response is needed.

1.9 Comment: One commenter (OAR-2002-0053-0016) requested clarification of § 60.334(j)(2). The commenter interpreted that if under option (ii) the percent by weight exceeds 0.8 weight percent, but under option (i) does not exceed 0.8 weight percent, no deviation need be reported. If this is not the case, EPA should clarify the statement in (ii) that reads "...shall evaluate excess emissions according to paragraph (j)(2)(i)."

Response: If the sulfur content of the fuel being delivered is above 0.8 weight percent, but the fuel in the tank is found to contain less than 0.8 weight percent sulfur after mixing the new and existing batches, then an excess emission does not need to be reported. Note that the term "deviation" has been removed from the final rule, due to overlap with the term for "excess emissions." For simplicity, we have removed the term "deviation" from the final rule. We believe that the proposed regulatory text is already clear with respect to this scenario and thus have not made any changes to it.

2.0 Monitoring

2.1 Continuous Monitoring

2.1.1 Comment: Numerous comments were received on the proposed continuous monitoring provisions. Four commenters (OAR-2002-0053-0008, OAR-2002-0053-0018, OAR-2002-0053-0019, and OAR-2002-0053-0047) stated that EPA should withdraw the optional continuous emission monitoring provisions under §§ 60.334(c), (e), and (f) for turbines that do not use water or steam injection to comply with the applicable NO_x emission standards.

Commenter OAR-2002-0053-0014 requested that EPA make clear that the choice of whether to use a NO_x CEMS is entirely at the discretion of the source owner or operator, even in those cases where a NO_x CEMS is installed. The commenter also requested that EPA make clear that nothing in the rule is intended to impose new requirements, or to alter or prevent other determinations regarding the adequacy of monitoring to comply with subpart GG. This commenter and commenter OAR-2002-0054-0013 recommended that EPA make clear in the final rule or preamble that (1) alternatives approved by state and local agencies under state authority, or delegation of authority from EPA are also valid, and (2) these amendments do not impose any new requirements, or require revision of existing permits, but simply provide several pre-approved options for sources that do not want to seek case-by-case approval.

Commenter OAR-2002-0053-0020 recommended the addition of language to § 60.334(c) indicating that existing subpart GG turbines without water or steam injection that are not required to implement continuous direct or indirect NO_x monitoring under their current approvals may continue to operate under the provisions of their current approvals. The commenter stated that an annual NO_x stack test could serve as an appropriate alternative to a NO_x CEMS or parametric monitoring for an existing subpart GG turbine with low annual utilization (< 1500 hours per year). For a small baseload turbine, an existing quarterly stack testing requirement would be an appropriate CEMS or parametric monitoring alternative.

Four commenters (OAR-2002-0053-0010, OAR-2002-0053-0013, OAR-2002-0053-47, and OAR-2002-0053-0048) stated that the proposed revisions would wrongly impose significant new requirements for ongoing NO_x compliance monitoring on mid-range stationary gas turbines and turbines in natural gas transmission. Commenter OAR-2002-0053-0013 gathered over 100 permits, including construction and Title V permits, for turbines subject to the NSPS. Examination of the gathered permits showed that continuous monitoring of emissions or parameters has typically not been required. The commenters expressed opposition to the provisions proposed in § 60.334(c), which they believed fail to address existing mid-range turbines subject to the NSPS because the vast majority of these turbines have neither CEMS nor an EPA-approved petition for alternative monitoring. Even natural gas transmission turbines with emission limits dramatically lower than the current NSPS limits are not typically required to install CEMS. Additionally, lean premix turbines have little possibility of exceeding the NSPS emission limit as it currently stands. The commenters requested that EPA revise § 60.334(c) to clearly state that monitoring requirements included in existing permits should not be revised as a result of this rulemaking. The commenters also did not support the provisions proposed in §§ 60.334(e) and (f) because they would impose significant new regulatory requirements on new NSPS turbines in natural gas transmission service and other mid-range units. In addition, Commenter OAR-2002-0053-0013 stated that in the memo in the docket (II-B-1), EPA ignored the costs for the significant new requirements which would be imposed, since most of the natural gas transmission and other mid-range units do not currently have CEMS installed. Therefore, in their opinion, EPA has failed to estimate the true impacts of the rulemaking, including the impacts related to increased monitoring, recordkeeping and reporting requirements for their industry. The commenters recommended that EPA revise §§ 60.334(e) and (f) so that they do not impose CEMS or continuous parameter monitoring requirements on owner/operators that are not otherwise required to use CEMS or continuous parametric monitoring, and to consider the current Agency approved NOx compliance monitoring techniques that are used by the natural gas transmission industry for NSPS turbines as alternatives to the continuous monitoring provisions included in Part 75.

Two commenters (OAR-2002-0053-0013, OAR-2002-0053-0020) stated the EPA should not rely on the May 31, 1994 memorandum from John Rasnic (EPA Applicability Determinations Index, Control No. 9700124) regarding compliance monitoring for turbines that use technology other than water injection as the basis for the proposed subpart GG revisions. Commenter OAR-2002-0053-0013 requested that the 1994 memorandum be formally withdrawn by the agency.

Two commenters (OAR-2002-0053-0013, OAR-2002-0053-0048) suggested that if EPA intends to impose new monitoring requirements for NSPS turbines, EPA should issue a new proposal with that intent expressly stated. Commenter OAR-2002-0053-0013 further stated that this proposal should include the full range of compliance monitoring for natural gas combustion turbines, as currently approved by EPA in existing permits for NSPS turbines, and should be performed in conjunction with the revisions of the NSPS emission standards.

Response: We have clarified in the preamble that nothing in this section is intended to impose new requirements for turbines constructed between 1977 and the effective date of these rule revisions. Instead, we have described a number of acceptable continuous compliance methodologies (e.g., the use of CEMS) for these units. We have added language to the preamble and rule which clarifies that continuous compliance methodologies already approved by EPA or by the local permitting authority are still valid. We do not agree that these revisions would impose new requirements for these turbines. We have ensured that the regulatory language is clear with respect to the use of CEMS as an option, and also made sure that any previously already approved methods are still valid. Hence, for existing Subpart GG turbines, there are no compliance costs associated with these amendments.

2.1.2 Comment: One commenter (OAR-2002-0053-0019) stated that EPA should amend the monitoring provisions of § 60.334(a) to clarify that monitoring applies only to those turbines that must use water or steam injection to control NO_x emissions "to comply with the NO_x standards under § 60.332(a)." The commenter noted that some turbines may be able to comply with the subpart GG NO_x standard uncontrolled, but need water or steam injection to comply with a more stringent NO_x standard.

Response: We do not agree with the commenter's suggested clarification that the monitoring requirements should apply only to turbines that use steam or water injection to control NOx emissions to comply with the NOx standards under § 60.332 (a). Water injection is mentioned in section 60.334(a) because it was the only emission control technology available for turbines when Subpart GG was originally proposed back in 1977. As we have done in the past, the use of alternative continuous monitoring methods may be approved by EPA on a case-by-case basis for turbines that do not use water injection to control NOx. Although a turbine may be able to meet the NOx emission standard with other control technologies, EPA believes that continuous monitoring is needed to ensure that the emission limit is being met at all times.

2.2 CEMS

2.2.1 Comment: One commenter (OAR-2002-0053-0014) requested that because it is possible to make the required correction to 15 percent O_2 under subpart GG using data from a CO_2 monitor, EPA should make it clear that sources have the option of monitoring either O_2 or CO_2 as a diluent. The commenter noted that § 60.334(b) appears to limit approval of NO_x CEMS to systems that use an O_2 monitor to correct the NO_x data to 15 percent O_2. According to the commenter, allowing the use of a CO_2 monitor is consistent with alternatives previously approved by EPA, which did not limit the use of 40 CFR part 75 diluent monitors to O_2.

Response: We agree that it is acceptable to make the required dilution correction with data from a CO_2 monitor. In the final rule, § 60.334(b) has been revised to include the CO_2 correction procedure from Method 20. The CO_2 readings must be converted to equivalent O_2 using equations F-14a or F-14b in part 75, appendix F.

2.2.2 Comment: One commenter (OAR-2002-0053-0025) requested that EPA clarify whether the revised subpart GG allows application of the 40 CFR part 75 O_2 (or CO_2) Diluent Cap provisions, or if an Alternative Petition must be submitted to obtain approval for use of this 40 CFR part 75 data reduction feature. If this 40 CFR part 75 option is not allowed under the current version of subpart GG, the commenter requested that the rule be revised to allow use of this option. The commenter noted that in previous subpart GG alternative monitoring provisions, EPA has approved the use of 40 CFR part 75 Diluent Cap procedures, which allow substitution of an O_2 value of 19 percent for any hour that measure O_2 greater than 19 percent.

Response: We agree that it is acceptable to provide a diluent cap procedure for reducing CEMS data. This comment has been incorporated. Section 60.334(b)(3)(i) of the final rule allows the diluent cap value of 19.0 percent O_2 to be used to calculate the NO_x emissions whenever the quality-assured hourly O_2 concentration measured by the O_2 monitor (or calculated from a CO_2 monitor reading) is greater than 19.0 percent O_2. No alternative petition will be required.

2.2.3 Comment: One commenter (OAR-2002-0053-0014) expressed the view that the proposed rule failed to address the use of NO_x concentration data that have been "bias adjusted" under 40 CFR part 75. The commenter believed that EPA should acknowledge that sources cannot be required to use bias adjusted data, as was done in 40 CFR part 60, subpart Da. The commenter noted that some turbines with emissions significantly lower than their subpart GG limit may prefer to simplify their reporting by utilizing the same bias adjusted data for subpart GG and 40 CFR part 75 and suggested the EPA make reporting of bias adjusted data for "excess emissions" monitoring optional.

Response: The commenter's suggestion was not incorporated. Part 75 combustion turbines that use CEMS for NO_x compliance are required to monitor and report the NO_x emission rate in lb/mmBtu on an hourly basis. To achieve this, a NO_x-diluent CEMS is used to continuously measure the NO_x concentration (ppm) and either the percent O_2 or percent CO_2. These measured gas concentrations are used to calculate the required hourly NO_x emission rates. Under Part 75, the relative accuracy test audit (RATA) of a NO_x-diluent CEMS is performed on a lb/mmBtu basis. If, during the RATA, the NO_x emission rates calculated from the CEMS data are biased low with respect to the emission rates derived from the EPA reference methods, a bias adjustment factor must be applied to the subsequent hourly NO_x emission rates. Since the bias adjustment factor is applied to the lb/mmBtu NO_x emission rates and not to the NO_x ppm values, and since diluent concentration data are never adjusted for bias under Part 75, there is no need to mention bias-adjusted data in Subpart GG. The Subpart GG emission limits are in units of ppm of NO_x, corrected to 15 percent O_2. Therefore, any Part 75 NO_x concentration or O_2 data used to assess compliance with these emission limits would not be bias-adjusted.

2.2.4 Comment: One commenter (OAR-2002-0053-0003) urged EPA to use its 67 FR 39602 *et seq*. (June 10 2002) $PM_{2.5}$ precursor foundation to impose a NH_3 CEM obligation on all gas turbines that utilize SCR as NO_x control. The commenter stated that EPA should require sources to identify NO_x and NH_3 emissions on a pounds per calendar quarter basis and on an average pounds per billion gross calorific value (GCV) Btu average over a calendar quarter and to submit the four data items as a report to the permitting agency such that they promptly become a public record.

Response: Since ammonia is not regulated under this subpart, we do not support adding a continuous monitoring requirement for ammonia to the NSPS.

2.2.5 Comment: One commenter (OAR-2002-0053-0025) suggested that in § 60.334(b)(4) it would be helpful to explicitly reference 40 CFR part 60 appendix F in conjunction with § 60.13 as one alternative for performing data quality assurance. The commenter stated that to their knowledge, § 60.13 itself does not include any quality assurance provisions and simply references appendix F.

Response: Continuous emission monitoring systems are used as an alternative to water to fuel ratio monitoring, to identify and report periods of excess emissions, and therefore Appendix

F procedure 1 is not mandatory. Section 60.334(b)(4) has been removed.

2.2.6 Comment: One commenter (OAR-2002-0053-0027) recommended that EPA delete the 7-day drift test requirement, if not for all units, then certainly for gas turbines that operate infrequently. The commenter said that the 7-day drift test required in 40 CFR part 60 is unnecessary and may be unrepresentative for units that operate only periodically. According to the commenter, a drift test in the form of a daily calibration error test is done every day and these tests are more than adequate to bring potential drift problems to the attention of CEMS technicians; 40 CFR part 75 allows the time to be considered to be continuous even with interruptions.

Response: The purpose of the initial 7-day drift test requirement is to assure that the CEMS is capable of operating in a stable manner from day-to-day. The performance specification for the test is twice as tight as the calibration error specification for daily operation of the monitor. The 7-day drift test thus helps to screen out poorly designed CEMS.

To address the commenters' concern about performing the test for units that operate infrequently, the final rule allows the test to be done over 7 consecutive operating days, rather than 7 calendar days. Also, note that a Subpart GG turbine which is subject to Part 75 is exempted from the 7-day test if the unit qualifies as a peaking unit under §72.2.

2.2.7 Comment: Two commenters (OAR-2002-0053-0013, OAR-2002-0053-0047) stated that some turbines in the gas transmission industry are diffusion flame combustors, yet are small (1200 HP, 11 MMBTU/hr). The commenter feels that since currently, the manufacturer guarantee is 100 ppm while the NSPS emission limit is 150 ppm NOx, that a mandatory CEMS requirement is inappropriate and imposes an unreasonable regulatory burden.

Response: As was stated in the preamble, we did not intend to impose any new requirements for existing Subpart GG turbines through the promulgation of this rule. We have clarified in the final rule that (1) alternatives approved by state and local agencies under state authority, or delegation of authority from EPA are also valid, and (2) these amendments do not impose any new requirements, or require revision of existing permits, but simply provide several pre-approved options for sources that do not want to seek case-by-case approval.

2.3 Parametric

2.3.1 Comment: Three commenters (OAR-2002-0053-0013, OAR-2002-0053-0010, OAR-2002-0053-0047) did not support the proposed changes presented in § 60.334(f), which address continuous parameter monitoring as an alternative to CEMS for new turbines that do not use steam or water injection to control NO_x emissions. The commenters noted that continuous parameter monitoring is not consistent with monitoring typically required for mid-range stationary gas turbines, including turbines used in natural gas transmission service, and would impose significant new regulatory requirements on these. Commenters OAR-2002-0053-0013 and OAR-2002-0053-0047 recommended that EPA revise the provisions in the final rulemaking to effect EPA's original intent of codifying the option to use continuous parameter monitoring, when otherwise required for other reasons such as 40 CFR part 75, without imposing significant new requirements on other owner/operators. The commenter also recommended that EPA explicitly state in the preamble that permitting authorities, under Title V periodic monitoring or other programs, are not restricted to continuous monitoring of emissions or parameters and may continue to consider the full range of compliance monitoring options for gas-fired turbines. Commenter OAR-2002-0053-0010 supported EPA's goal of allowing owner/operators the flexibility to use data from continuous parameter monitoring already required for other reasons to demonstrate compliance with the NSPS, however, the commenter does not support a mandatory requirement for continuous parameter monitoring and requests that EPA withdraw § 60.334(f) from the direct final and proposed rules.

In addition, commenters OAR-2002-0053-0013 and OAR-2002-0053-0047 stated that new lean premix turbines have little possibility of exceeding the NSPS emission limit as it currently stands. Indeed, verification of lean premix combustion ensures NOx emissions at levels far below the current NSPS emission limit. Equally, information about operation outside of lean premix does not provide meaningful information about whether a unit has failed to comply with the current NSPS emission limit.

Response: As was stated in the preamble, we did not intend to impose any new requirements through the promulgation of this rule. We have clarified in the final rule and preamble that these amendments do not impose any new requirements but simply provide several pre-approved options for sources that do not want to seek case-by-case approval.

In regards to the comment that new lean premix turbines are able to comply with the current emission limit with little possibility of exceeding the standards, we plan to revise the emission limitations during the upcoming phase of this rulemaking.

2.3.2 Comment: One commenter (OAR-2002-0053-0004) opposed and requested the removal of the parameter monitoring plan requirement proposed in § 60.334(g). They further state that it does not streamline the differences between subpart GG and 40 CFR part 75 Appendix E requirements. Appendix E adequately addressed this issue. One commenter (OAR-2002-0053-0013) requested that the provisions in § 60.334(g), which address the use of performance test data to establish acceptable parameter ranges, be revised to provide the opportunity for owner/operators to establish and/or adjust operating parameter limitations based on performance tests, engineering analysis, design specifications, manufacturer recommendations or other applicable information, such as a performance test on a similar unit. Since gas transmission units are load following, it may not be possible to operate at specific load conditions at the predetermined time scheduled for the performance test, and maximum and minimum load condition emissions may not be seen during the performance test. A similar unit, however, can exhibit representative emissions for developing parameter limitations.

Response: The requirement to develop and maintain a parameter monitoring plan has been retained in the final rule. For units that use continuous parameter monitoring to assess compliance with the Subpart GG emission limits, we believe it is essential for the owner or operator to clearly identify the monitored parameters and their acceptable ranges, and to provide the technical basis for selecting those parameters and ranges. Section 60.334 (g) of the final rule allows the owner or operator to supplement the parametric data recorded at the time of the initial performance test with other types of information, in order to establish the appropriate parametric ranges and values.

In response to the comment about Appendix E units, §§ 60.334 (f) and (g) of the final rule make it clear that the if the owner or operator performs the parametric monitoring described in section 2.3 of Part 75, Appendix E and maintains the QA plan described in § 1.3.6 of Part 75, Appendix B, this will satisfy the requirements of Subpart GG. For the sake of completeness, for low mass emissions (LME) units, the final rule also allows the owner or operator to use the QA plan described in § 75.19 (e)(5) to satisfy the parameter monitoring plan requirements of Subpart GG.

2.3.3 Comment: Two commenters (OAR-2002-0053-0013 and OAR-2002-0053-0047) stated that continuous parameter monitoring is not appropriate for new diffusion flame turbines subject to NSPS. Some models of diffusion flame combustors are installed for the natural gas industry for which there are no predictive emission monitoring systems available. Development of one would impose an unreasonable burden on the industry.

Response: Predictive emission monitoring systems, or PEMS, are very different from the parameter monitoring option that we have added to the final rule. Continuous parameter monitoring refers to the monitoring of operating conditions or parameters, such as turbine exhaust temperature, compressor discharge pressure, or any others which may be indicative of the unit's NOx formation characteristics. Predictive emission monitoring systems, on the other hand, predict actual emission rates or concentrations from operating parameters that affect NOx formation. Parameter monitoring oversees operating parameter boundaries, while PEMS measure emission rates or concentrations. We believe that adding the option to continuously monitor parameters that are indicative of the unit's NOx formation characteristics would not impose an unreasonable burden on the industry. No changes have been made from the proposed rule to the final rule to address this comment.

2.4 Other

2.4.1 Comment: One commenter (OAR-2002-0053-0014) did not believe that EPA's attempt to distinguish between "excess emissions" and "deviations" is necessary since neither a violations under subpart GG. The commenter was also concerned that the choice of the term "deviation" could cause confusion in the context of Title V permits and State Implementation Plans (SIP) and suggested the EPA either continue to use the term "excess emissions" for all reported parameters under subpart GG, or follow the terminology adopted in the Compliance Assurance Monitoring rule at 40 CFR part 64, which refers to parameter exceedances as "excursions."

Response: We agree with the commenter that it is not necessary to distinguish between "deviations" and "excess emissions." Both terms represent an averaging period during which a monitored parameter exceeds the limit specified in the rule. Therefore, use of the term "deviation" in addition to "excess emissions" would be redundant. The final rule does not use the term "deviation."

2.4.2 Comment: One commenter (OAR-2002-0053-0016) requested clarification on § 60.334(j)(2), which says that periods of excess emissions and monitor downtime end on the date and hour of the next valid sample. The commenter stated that EPA should clarify that the period of excess emissions and/or monitor downtime from the start date to the next valid sample includes only unit operating hours.

Response: We agree with the commenter and have revised § 60.334(j)(2) in the rule accordingly.

2.4.3 Comment: One commenter (OAR-2002-0053-0004) opposed the 4-hour averaging period to determine compliance. The commenter believed that EPA should base averaging times on the stated permit conditions of a PSD/NSR permit issued by the permitting authority and that subpart GG should remain silent on this issue other than the time it takes to conduct the required compliance stack testing.

Response: We do not agree with the commenter. The 4-hour averaging period has been retained in the final rule. The commenter is incorrect in asserting that Subpart GG should be silent on the issue of the averaging period for excess emission reporting. Each NSPS subpart that requires excess emission monitoring and reporting with respect to a particular emission limit must specify an averaging period. If a Subpart GG turbine is subject to another more stringent NO_x emission limit with a different averaging period than Subpart GG (e.g. a permit limit), and if the unit's operating permit requires excess emission reporting with respect to that limit, then two separate excess emission reports must be filed, i.e., one to satisfy Subpart GG requirements and the other to meet the permit requirement.

2.4.4 Comment: One commenter (OAR-2002-0053-0025) requested that the 4-hour rolling averaging period for NO_x emissions extend backward three operating hours, not three quality assured operating hours. The commenter noted that the standard CEMS vendor software is configured to look back a fixed number of calendar or on-line hours, but not quality assured hours.

Response: We agree with the commenter, and have revised the final rule accordingly. "Quality assured" has been removed when used in reference to the rolling averaging period.

2.4.5 Comment: One commenter (OAR-2002-0053-0027) noted that 40 CFR part 75 exempts gas turbines firing natural gas or less than 10 percent oil from opacity monitoring. According to the commenter, many, if not most, states are incorporating opacity or particulate limits with periodic monitoring requirements into permits for new gas turbines. The commenter felt that these permit conditions requiring an opacity meter are unnecessary and should be avoided except in a case-by-case situation where either more than 10 percent oil is used, or an unusual fuel (e.g. high ash) is used.

Response: Opacity is not regulated under Subpart GG. Furthermore, this comment does not pertain to any of the proposed revisions to Subpart GG. Thus, we have not made any changes to the final rule related to this comment.

2.4.6 Comment: One commenter (OAR-2002-0053-0024) noted that, depending on the fuel being fired, a turbine may or may not use water injection. The commenter recommended clarifying § 60.334 to reflect this and to clarify that water monitoring and reporting is not always required. The commenter suggested that the clarification be accomplished simply by changing the turbine type designation to a process designation, such as "diffusion flame process."

Response: We agree with the commenter. The rule has been revised to clarify that when a turbine is running in lean premix mode, then it is considered a lean premix combustion turbine, and when it is running in diffusion flame mode, then it is considered a diffusion flame combustion turbine. This clarification has been made to the definitions in the final rule under § 60.331 (w) and (x) for lean premix stationary combustion turbine and diffusion flame stationary combustion turbine.

3.0 Test Methods and Procedures

3.1 Comment: One commenter (OAR-2002-0053-0010) supported the addition of text to § 60.335(b)(2) allowing testing at four load points in the normal operating range of the gas turbine.

Response: No response is needed.

3.2.1 Comment: One commenter (OAR-2002-0053-0019) requested that EPA allow performance tests to be conducted in the normal operating range of the gas turbine and allow for testing units that cannot be operated at "peak load" due to process constraints. The commenter recommended that EPA revise § 60.335(b)(2) as follows:

> "...The 3-run performance test required by § 60.8 must be performed within ± 5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice."

Response: The final rule incorporates the commenter's suggested revisions to §60.335(b)(2). We believe that it is reasonable to make allowance for units that are not physically capable of attaining 90-to-100 percent of peak load.

3.2.2 Comment: One commenter (OAR-2002-0053-0025) suggested that if the permitted operating range of a turbine is sufficiently narrow, the required number of load levels for performance testing should be appropriately reduced. The commenter suggested that a minimum load level spacing of 20 percent be established.

Response: We believe that the requirement for four points for performance testing is necessary. The purpose of the data is to establish a water to fuel ratio. Two points are not enough to establish a statistically relevant relationship. Thus, we have not made any changes from the proposed rule to the final rule related to this comment.

3.3 Comment: One commenter (OAR-2002-0053-0024) believed that § 60.335(b)(2) should use the term "dispatched load range" instead of "normal operating range," to be consistent with 40 CFR part 75 appendix E. The commenter recommended that the term be defined in § 60.331 and that the definition mirror the appendix E definition to include both normal operating range, or if the operation is expected to change, the projected dispatched load range.

Response: Appendix E only applies to peaking units. Peaking units are required to do the initial performance test and use this data to plot the heat input rate versus the NO_x emission rate. They use this plot in conjunction with their measured heat input rate to calculate the NO_x emission rate, in lieu of using a CEMS. They are required to retest at least once every 20 calendar quarters (5 years). Therefore, Appendix E units might want to use the load to be dispatched in the future, but we feel that the terminology "normal operating range" is appropriate for this rulemaking.

3.4 Comment: One commenter (OAR-2002-0053-0024) stated that § 60.335(b)(2) should refer to a "4-run" performance test rather than a "3-run" test.

Response: The commenter provided no rationale for this recommendation. Section (which is referenced in § 60.335(b)(2), calls for a performance test that consists of three separ runs. The recommended language was not incorporated in the final rule.

3.5 Comment: Two commenters (OAR-2002-0053-0018, OAR-2002-0053-0019) no that the reference in § 60.335(a) to the procedures in "§ 6.5.6.3(a) and (c)" of 40 CFR part 75, appendix A should be changed to "§ 6.5.6.3(a) and (b)." The commenters noted that § 6.5.6.3 pertains to acceptance criteria and conditional provisions for traverse points to be used during sampling and that paragraph (c) of that section only addresses recordkeeping. The commenter questioned whether EPA had intentionally not cited paragraph (b) of that section, which conditionally provides for using a single point for conducting sampling. If the omission was intentional, the commenters urged EPA to reconsider the issue in the interest of consistency wi 40 CFR part 75. Similarly, one commenter (OAR-2002-0053-0022) requested that the single measurement point identified in §§ 6.5.6(b)(4) and 6.5.6.3(b) of 40 CFR part 75 appendix A be added to the final rule. The commenter noted that the stratification testing procedure for a sing measurement point is identical to the long and short measurement lines and the acceptance criteria for a single measurement point is more stringent.

Response: We agree with the commenter that measurement at a single point is appropriate in certain situations. In the interest of consistency with 40 CFR part 75, we have indicated in the final rule that data collected following § 6.5.6.1 can be used. We have also changed the initial performance test requirements in § 60.335(a) to reflect that this option is available. However, because recently proposed revisions to Method 7E have more restrictive criteria at lower concentrations than those in § 6.5.6.3 of 40 CFR part 75, we believe that it is no appropriate to allow consistency in this case. Therefore, we have removed reference to § 6.5.6.3 of 40 CFR part 75 in this rule. It is still possible to use the same data and choose the more restrictive number of sampling locations.

3.6 Comment: Two commenters (OAR-2002-0053-0018, OAR-2002-0053-0019) commended that a subparagraph be added to § 60.335(a) to clearly distinguish requirements for vners and operators that opt for using ASTM D6522-00 or EPA Method 7E instead of Method). Commenter OAR-2002-0053-0019 suggests that the following should be appended to ragraph (a): "Other acceptable alternative reference methods and procedures are given in ragraph (c) of this section."

The commenters noted that much of the new language EPA has added to the test methods and procedures under § 60.335(a) pertains to relative accuracy test audits (RATAs) and as these requirements are being applied to performance testing, any reference to a RATA is inappropriate and should be removed. The suggested changes to § 60.335(a) are given in the comments.

Response: We agree with the commenter that requirements for those opting to use ASTM D6522-00 and/or EPA Method 7E should be clarified. Section 60.335(a) has been modified accordingly. We also agree that references to a RATA in § 60.335(a) should be deleted, and replaced with "performance testing." This change has been made to the rule.

3.7 Comment: One commenter (OAR-2002-0053-0019) stated that for turbines that do not have auxiliary-fired waste heat recovery units, EPA should waive the requirement to conduct a preliminary O_2 or CO_2 traverse, as required by Method 20, or as alternatively provided by 40 CFR part 75, appendix A (§ 6.5.6). The commenter said that EPA should allow a single sample point for conducting performance tests to demonstrate compliance with pollutant concentration standards for stationary gas turbines.

Response: Although it is possible for some turbines to not have significant stratification in the stack, we believe that this needs to be demonstrated and documented before allowing a reduced number of sample points. We have added provisions to § 60.335(a)(5) that reduce traverse points after initial documentation that stratification does not exist.

3.8 Comment: One commenter (OAR-2002-0053-0019) requested that EPA allow owners and operators to use a multi-hole probe that meets EPA specifications for performance tests in lieu of a preliminary O_2 or CO_2 traverse required by Method 20 or a stratification test required by 40 CFR part 75, appendix A.

Response: We agree with the commenter, and appropriate language has been added to § 60.335(a) of the final rule, allowing the use of a multi-hole probe that is designed and documented to sample equal volumes from each hole simultaneously at the required points.

3.9 Comment: Two commenters (OAR-2002-0053-0014, OAR-2002-0053-0025) requested that EPA revise § 60.335(a), which specifies that owners or operators choosing to use EPA Methods 7E and 3A (or 3) for NO_x performance testing must perform a stratification test for NO_x and diluent under 40 CFR part 75, appendix A, § 6.5.6.1(a) - (e) in order to determine if subsequent RATA testing will occur along a short or long reference method measurement line. Commenter OAR-2002-0053-0014 appreciated EPA's proposal to add the option of using a short measurement line but did not understand why a source that chooses to use the long reference measurement line would need to perform the stratification test. The commenter noted that EPA's prior approvals for use of Method 7E did not include a requirement to perform a stratification test if the long measurement line was used. Commenter OAR-2002-0053-0025 stated that if a source agrees to use the most stringent options (i.e. the long measurement line), it would seem unnecessary to require a stratification check.

Response: Section 60.335(a) applies to a performance test, not a RATA. We agree that if a source provides initial documentation that stratification does not exist, it is appropriate to have a reduced number of sampling points. We also agree that a source can skip the stratification test and default to using a multi-hole probe, and § 60.335 has been modified accordingly. However, because it is possible to have spatial stratification due to several reasons such as ammonia injection that would not be accounted for with the long measurement line, we are requiring documentation that stratification does not exist. We have also indicated that the use of data following § 6.5.6.1 of 40 CFR part 75 can be used. In addition, we have reserved a paragraph in section 60.335(a)(5)(i)(A) that will give the option of using stratification testing protocols that were proposed for Methods 7E and 3A in a separate Federal Register notice.

4.0 ISO Correction

4.1 Comment: Three commenters (OAR-2002-0053-0010, OAR-2002-0053-0013, and OAR-2002-0053-0047) supported EPA's proposal to make correction of emissions to ISO conditions optional for lean premix turbines.

Response: No response is needed.

4.2 Comment: Two commenters (OAR-2002-0053-0004, OAR-2002-0053-0016) recommended the removal of the ISO correction calculation. According to commenter OAR-2002-0053-0004 the calculation is not practical for the modern turbine, and incorporation of the ISO correction factor within a CEMS requires burdensome administrative changes and unnecessary certification. As an alternative to removal of the ISO correction calculation, the commenter expressed support for making the ISO correction optional for specific gas turbines.

Commenter OAR-2002-0053-0016 recommended that EPA harmonize subpart GG with 40 CFR part 75 monitoring requirements, eliminating any requirement to correct to ISO conditions, instead correcting to 15 percent O_2. The commenter also said that EPA should recognize the use of water injection as an add-on emission control device. The commenter noted that many lean premix units operate in limited use diffusion flame mode with water injection for emissions control and recommended that EPA recognize these dual-fuel units as lean premix where the primary fuel is natural gas combusted in lean premix mode. Further, they suggested that EPA exempt from ISO correction units that employ water injection when monitored in accordance with 40 CFR part 75 requirements. Similarly, one commenter (OAR-2002-0053-0028) recommended that diffusion flame units using water injection to control NO_x be exempt from the ISO data correction. Their rationale is that water injection cools the flame temperature to a level where NO_x is no longer primarily produced by thermal processes (much like lean premix, where the majority of NO_x is not produced thermally).

One commenter (OAR-2002-0053-0025) suggested that any turbine equipped with a NO_x CEMS be provided the option of not applying the ISO correction, irrespective of its design or configuration.

One commenter (OAR-2002-0053-0027) observed that the use of the ISO correction equation has no technical basis for gas turbines with lean premix combustors or for diffusion flame combustors with water or steam injection and NO_x levels significantly below the subpart GG levels of 75 ppm.

Response: No adequate rationale was provided for exempting all turbines from the ISO correction factor. The ISO correction factor was initially developed for diffusion flame units, and no rationale has been provided for making it optional for these units. We believe the ISO correction factor continues to be appropriate for diffusion flame units and water or steam injected units. The need for the ISO correction factor will continue as we begin the process of revising the emission limits in Subpart GG in the near future. We have also clarified in the final rule that when a unit is capable of using both lean premix and diffusion flame modes, it is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

4.3 Comment: One commenter (OAR-2002-0053-0027) remarked that the EPA, in a policy letter from Bruce Jordan, Director Emission Standards Division, dated June 2, 1997 approved the use of General Electric's (GE's) gas turbine control algorithm in lieu of the subpart GG ISO correction equation for GE diffusion flame combustion, heavy duty (frame) gas turbines requiring either water or steam injection for NO_x abatement. The commenter did not specify how this fact was related to any of the proposed revisions or how the commenter wanted to see this statement addressed.

Response: Although, as noted by the commenter, this petition was approved by us in 1997, it is important to note that it only applied to GE heavy duty diffusion combustion turbines using the Mark 5 controller.

4.4 Comment: Two commenters (OAR-2002-0053-0004, OAR-2002-0053-0016) recommended that EPA remove the requirement to record ambient conditions when operating a turbine. Commenter OAR-2002-0053-0004 stated that this requirement is burdensome and unnecessary and adds an administrative requirement that has no bearing on the environment. One commenter (OAR-2002-0053-0025) stated that for turbine units that are exempt from applying the ISO correction or which apply worst case ambient conditions to make the ISO corrections, the reporting of ambient conditions is unnecessary and represents a significant burden, since they are not collecting this data on-site.

Response: The ambient condition data is not used for any purpose other than the ISO correction. Therefore, we agree with commenter OAR-2002-0053-0004 that the requirement in the proposed §§ 60.334(j)(1)(i)(C) and (iii)(C) to report the ambient conditions is unnecessary for those turbines for which the ISO correction is optional under § 60.335(b)(1). Reporting of ambient conditions is also not necessary if an owner or operator chooses to calculate and apply a worst case ISO correction factor as specified in § 60.334(b)(3)(ii). Reporting of ambient conditions is still necessary for turbines that are required to use the ISO correction factor and do not opt to use a worst case ISO correction factor. We have changed the rule accordingly.

5.0 Emission Standards

5.1 Comment: One commenter (OAR-2002-0053-0003) urged EPA to update the standard for sulfur dioxide in § 60.333. The commenter recommended that EPA revise § 60.333(a) to set an emission limit for sulfur dioxide of 10 ppmvd @ 15 percent O_2. The commenter also recommended that § 60.333(b) be revised to limit the sulfur content of fuel burned in stationary gas turbines subject to Subpart GG to 0.050 percent by weight. Lastly, the commenter suggested that EPA add to § 60.333 a new paragraph (c) which would specify that no owners or operators subject to the provisions of Subpart GG should burn in any stationary gas turbine any fuel which contains sulfur in excess of 27 pounds per billion gross calorific value Btu fuel.

Response: We will address emission limits in a future rulemaking revising subpart GG. We have not made any changes to the emission limitations at this time.

5.2 Comment: One commenter (OAR-2002-0053-0003) stated that total re-composition of § 60.332 is in order. The commenter made the following points:

- Gross calorific value (GCV) is more common than lower heating value (LHV). No subpart GG text should reference LHV.
- The commenter requested a detailed explanation of EPA's 107.2 gigajoules (100 million Btu/hour) equivalence factor.
- The mixture of what is chemical heat input and what is electrical output in § 60.332 should be resolved with all of the fuel quantity (energy) input part expressed as GCV Btu, thousand GCV Btu, million GCV Btu, etc., and all electrical output expressed as kilowatt hours, megawatt hours, gigawatt hours, etc. Where power is used to express size of equipment, million GCV Btu per hour, megawatts, etc. should be used. In the interest of communication clarity, all references to joules should be removed.
- The following should be added: "No owner or operator subject to the provisions of this

subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain nitrogen oxides in excess of 330 pounds per billion GCV Btu fuel."

Response: These standards were originally promulgated in 1979 and all the technical justifications can be found in the background document. The background document for this rule is EPA-450/2-77-017b. We feel that the units are still appropriate for this rule. As stated before, all revisions to the emissions limits in Subpart GG will be addressed in a subsequent rulemaking.

5.3 Comment: One commenter (OAR-2002-0053-0030) said that EPA must review and revise the NO_x emission limits in § 60.332(a). According to the commenter, subpart GG is completely out of date and not adequately protective.

Response: We acknowledge the commenter's concern that the emission limits in Subpart GG need to be revised. Subsequent to this final rule, we will begin the regulatory process of revising the emission limits in Subpart GG.

5.4 Comment: One commenter (OAR-2002-0053-0014) stated that EPA should ignore comments asking EPA to impose new emission standards and otherwise significantly revise subpart GG to add new requirements or revise provisions that are not part of the proposal.

Response: Although we cannot revise the emission limits in this rulemaking, we are clarifying that we will begin the regulatory process to revise the standards soon after promulgation of this final rule.

6.0 Definitions

6.1 Comment: One commenter (OAR-2002-0053-0004) requested that EPA provide greater clarification and definition of what constitutes a lean premix combustor. For example, some turbines that burn dual fuels operate using two different modes when burning natural gas versus fuel oil and the commenter stated that the backup fuel operation should be considered for inclusion in the definition for lean premix units. The commenter recommended the use of definition for a "gas-fired" unit found in 40 CFR part 72 to accommodate a unit that predominately fires in the lean premix mode of operation, but has limited operating hours for firing fuel oil (diffusion flame operation).

predominantly fires in lean premix mode but also uses diffusion flame mode on occasion, the owner or operator may need to use the ISO correction factor when this unit is in diffusion flame mode. Therefore, calling all of these units "gas fired," and changing the rule to exempt "gas fired" units from the ISO correction factor would preclude the requirement for the ISO correction which is not consistent with our goal. Third, lean premix units that choose parametric monitoring must monitor parameters which determine whether the unit is operating in the lean premix mode, and if this category were changed to "gas fired" units including the diffusion flame firing mode, then the requirement to monitor such parameters ensuring that the unit is firing in lean premix mode would be pointless.

We have clarified in the final rule that when a unit which is capable of using both lean premix and diffusion flame modes, it is considered a lean premix unit when it is in the lean premix mode, and it is considered a diffusion flame unit when it is in the diffusion flame mode. We have clarified this point in the definitions section, § 60.331 of the final rule, and the preamble.

6.2 Comment: One commenter (OAR-2002-0053-0027) said that the definition of lean premix stationary combustion turbine in § 60.331(x) fails to recognize that the mixing of air and fuel in some cases may take place in an area normally interpreted to be part of the combustor. The commenter suggested that the definition be clarified to state "...any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before combustion. Lean premixed combustion has a flame front between the incoming premixed fuel/air mixture and combusted gases."

Response: We agree with the commenter. The definition has been modified to be consistent with the definition for "lean premix technology" in the CT NESHAP rule. "Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber."

6.3 Comment: One commenter (OAR-2002-0053-0027) suggested that the definition of "stationary gas turbine" in § 60.331(a) be broadened to include additional components, consistent with EPA's intent for the concept of reconstruction. The commenter recommended the following definition of "stationary gas turbine":

"A stationary gas turbine includes all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems; control systems; and any ancillary components and sub-components comprising any simple cycle stationary gas turbine; and regenerative/recuperative cycle stationary gas turbine; the gas turbine portion of any stationary cogeneration cycle combustion system; or the gas turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the gas turbine is not selfpropelled, nor is it intended to be propelled, while performing its function. However, it may be mounted on a vehicle for portability."

Similarly, commenter OAR-2002-0053-0013 encouraged EPA to clarify the regulations regarding the use of turbine component replacement for routine turbine overhauls to state that the routine component replacements do not trigger NSPS applicability.

Response: We have not changed the definition of "stationary gas turbine" in the final rule since we feel the current definition is appropriate. We did not propose any changes to § 60.331(a) and will not make the recommended revisions without first providing the opportunity for public comment.

6.4 Comment: One commenter (OAR-2002-0053-0027) recommended that the definition of emergency turbine at § 60.331(e) be broadened such that it recognizes the emergency turbine function for situations where power failures do not affect an entire facility. The commenter also stated that operation of emergency turbines should not be limited to only those times when the primary power source has been rendered inoperable by an emergency situation. The commenter recommended that EPA include more examples of emergency operation in the definition, including fuel and raw material curtailments.

Response: This comment pertains to a paragraph that was not being revised as part of this rulemaking. We have not made the recommended changes since no opportunity has been given to the public to comment on it.

6.5 Comment: One commenter (OAR-2002-0053-0027) suggested that the definition of diffusion flame stationary combustion turbine in § 60.331(y) be modified to read "Diffusion flame stationary combustion turbine means any stationary combustion turbine where the fuel and the air/oxygen in the combustor reach the flame front by 'diffusion'. The flame front is located between zones rich in fuel and zones rich in oxidant (air). Mixing of the fuel and air at the combustor may be enhanced through the use of mechanical devices such as swirl cups, nozzles or orifices prior to ignition."

One commenter (OAR-2002-0053-0011) urged EPA to maintain a consistent definition for "diffusion flame stationary combustion turbine" between the section 111, New Source Performance Standards and section 112, National Emission Standards for Hazardous Air Pollutants, Stationary Combustion Turbines.

Response: We do not agree with commenter OAR-2002-0053-0027, and believe that the proposed language is appropriate. No rationale was provided for the suggested changes to include more details in the mechanisms of diffusion. We agree with commenter OAR-2002-0053-0011, and have decided to keep the definition consistent with the definition for "diffusion ne technology" in the CT NESHAP rule.

6.6 Comment: One commenter (OAR-2002-0053-0012) believed that a more precise finition of fuel-bound nitrogen should be added to the definitions in § 60.331 in order to :arly define the fuel-bound nitrogen allowance for units that operate on gaseous fuels where the s is not a typical natural gas type fuel.

Response: No rationale was provided for this comment, nor was a suggestion made as to hat the definition should be. This definition has not been added to the final rule.

.0 Clarification

7.1 Comment: One commenter (OAR-2002-0053-0004) opposed any attempt to impose tricter emission limitations or averaging times, as well as recordkeeping and reporting, than that which is contained within their existing permits without a sound scientific basis to do so. The commenter stated that it is not quite clear if the direct final rule amendments will be applicable only to "new sources" built after the promulgation date of the direct final rulemaking; this should be evident in the final rule and stated as such.

Response: In this rulemaking, we are providing options that both new and existing sources may use. Where the regulation is only applicable to new sources, it is explicitly stated in the code.

7.2 Comment: One commenter (OAR-2002-0053-0010) suggested that the definition of "Y" in § 60.332 be changed to say "If the turbine heat rate is greater than 14.4, the value 14.4 should be used for Y in this calculation."

Response: We disagree with this comment and believe that the current language is clear and unambiguous. Therefore, we feel that the current wording is sufficient as we are not aware of any problems with its interpretation.

7.3 Comment: One commenter (OAR-2002-0053-0010) suggested that in §§ 60.332(a)(4) and 60.334(h)(2) the "nitrogen" be changed to "fuel-bound-nitrogen." The commenter also suggested changing the definition of "N" to denote "fuel-bound-nitrogen."

Response: We disagree with this comment and believe that the current language is appropriate. Currently, § 60.332(a)(4) states "If the owner or operator elects to apply a NOx emission allowance for fuel bound nitrogen, F shall be defined according to the nitrogen conte of the fuel during the most recent performance test..." It would be redundant and confusing to add "fuel bound" before "nitrogen content of the fuel." Section 60.334(h)(2) has the same wording, and it would also be inappropriate to add "fuel bound" prior to "nitrogen." No changes have been made in response to this comment.

7.4 Comment: One commenter (OAR-2002-0053-0010) suggested that the word "new" be removed from § 60.334(h)(4).

Response: We agree with the commenter. Using the word "new" in § 60.334(h)(4) is redundant and may be confusing to the reader. This change has been made to the final rule.

8.0 Other

8.1 Comment: Two commenters (OAR-2002-0053-0016, OAR-2002-0053-0025) requested clarification on the issue of compliance during startup and shutdown. Commenter OAR-2002-0053-0025 asked whether startup and shutdown hours can be excluded from the 4-hour NO_x CEMS rolling averages used for compliance determination. The commenter also asked how site specific startup and shutdown periods should be established and whether the site can simply use manufacturer's recommended durations. Commenter OAR-2002-0053-0016 stated that EPA should modify § 60.334(j)(1)(iii)(A) to add language clarifying that the average excludes emissions from startup, shutdown, and malfunctions.

Two commenters (OAR-2002-0053-0024, OAR-2002-0053-0027) remarked that the requirement in § 60.334(j)(1)(i)(A) that "any unit operating hour in which no water or steam is injected into the turbine shall also be considered a deviation" does not appear to exempt startup or shutdown transients. Commenter OAR-2002-0053-0027 said that any gas turbine equipped with steam or water injection for NO_x control would always have a deviation during startup and shutdown transients. According to the commenter, steam or water injection is usually initiated between 20 to 50 percent of base load during startup and is likewise discontinued during the shutdown transient. Commenter OAR-2002-0053-0024 recommended revising the wording of the last sentence of the section to read as follows:

> "Any unit operating hour in which no water or steam is injected into the turbine shall also be considered a deviation for purposes of reporting periods of startup, shutdown, and malfunction."

Response: In response to these comments, § 60.334(j) of the final rule has been revised to clearly state that excess emissions must be recorded during all periods of unit operation, including startup, shutdown and malfunction. Note that the term "deviation" has been removed from the final rule, and has been replaced by the term "excess emission" for all cases, due to overlap of these terms. All excess emissions are reported and categorized. Startup and shutdown are two of those categories. We recognize that even for well-operated units with efficient NO_x

emission controls, excess emission "spikes" during unit startup and shutdown are inevitable, and malfunctions of emission controls and process equipment occasionally occur. However, at *all* times, *including* periods of startup, shutdown and malfunction, § 60.11(d) requires affected units to be operated in a manner consistent with good air pollution control practice for minimizing emissions. Excess emission data may be used to determine whether a facility's operation and maintenance procedures are consistent with § 60.11(d).

8.2 Comment: One commenter (OAR-2002-0053-0027) expressed the opinion that the option to measure gas turbine NO_x emissions in the exhaust stream after the duct burner rather than directly after the turbine is not viable as written because it does not account for the additional NO_x contribution from the duct burner. The commenter stated that the rule should be changed to provide for the duct burner NO_x contribution.

Response: The purpose of this revision was to allow owners and operators the flexibility of making one measurement downstream of the duct burner since many turbines are able to comply with the NOx limit even with the potential NOx contribution resulting from the duct burner. Accounting for the NOx contribution from the duct burner would require two NOx measurements, which clearly defeats the purpose of this revision. Furthermore, owners and operators still have the option of simply measuring NOx emissions in the turbine exhaust, prior to the duct burner. For these reasons we disagree with the commenter and have not made any changes from the proposed rule to the final rule with respect to this provision.

8.3 Comment: One commenter (OAR-2002-0053-0005) supported the direct final rule and expressed appreciation for the numerous changes that make use of current monitoring technologies, analytical methodologies, and approved custom fuel monitoring schedules. The commenter observed that the updates to the rule provide common sense changes that help to streamline compliance while simultaneously maintaining air quality protection.

One commenter (OAR-2002-0053-0011) supported the proposed rule insofar as it would codify alternative testing and monitoring procedures that have previously been approved by EPA for individual facilities, as well as provide much needed updates to several provisions of the performance standard. The commenter urged EPA to implement the changes without further delay.

One commenter (OAR-2002-0053-0015) supported EPA's proposal and urged EPA to complete it, after addressing all submitted comments, and work with the states to implement the changes without further delay.

Two commenters (OAR-2002-0053-0013, OAR-2002-0053-0014) supported EPA's proposal to incorporate routinely approved monitoring and testing alternatives. Commenter OAR-2002-0053-0014 noted that other issues that would require revision of subpart GG and 40

CFR part 75 to resolve have been identified by stakeholders and requested that EPA commit to addressing those issues in a future rulemaking rather than delaying finalization of the improvements currently proposed. Commenter OAR-2002-0053-0013 encouraged EPA to move forward quickly with the noncontroversial aspects of the rulemaking.

Similarly, commenter OAR-2002-0053-0047 supports the EPA's efforts to streamline the NSPS requirements and remove burdensome requirements. Specifically, this commenter supports the Agency's proposal to remove requirements to monitor sulfur and nitrogen content for natural gas. This commenter also supports EPA's proposal to make the ISO correction optional for lean premix turbines.

Response: No response is needed.